Application for Reissue of

U.S. Patent No. 5,462,120

of

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for

"Downhole Equipment, Tools and Assembly Procedures for the Drilling, Tie-In and Completion of Vertical Cased Oil Wells Connected to Liner-Equipped Multiple Drainholes"

DOWNHOLE EQUIPMENT, TOOLS AND ASSEMBLY PROCEDURES FOR THE DRILLING, TIE-IN AND COMPLETION OF VERTICAL CASED OIL WELLS CONNECTED TO LINER-EQUIPPED MULTIPLE DRAINHOLES

FIELD OF THE INVENTION

Horizontal wells have been used extensively in heterogeneous reservoirs to intersect fractures and/or to reduce the detrimental effects of gas coning and water coning. It has been shown that such wells are capable of higher oil production rates than vertical wells drilled in the same reservoir. In most cases, the higher productivity more than offsets the higher cost of drilling and completion of the horizontal well. Theory predicts that the use of multiple horizontal drainholes correspondingly multiplies the total well productivity. Indeed many vertical cased wells connected to twin or multiple horizontal drainholes of medium (500–200 ft) and short (150–40 ft) radius of curvature have been successfully used in compact oil reservoirs, such as the Austin Chalk, in which open hole completion of the drainholes is applicable.

In many clastic reservoirs, however, the strength of unconsolidated sands or of friable sandstones may be insufficient to keep horizontal drainholes open. In such a case, the horizontal and deviated parts of each drainhole must be kept open with a tubular liner which is tied to the vertical casing using conventional equipment and known assembly procedures. This has been done in many different clastic reservoirs, containing light or heavy oil, for horizontal wells consisting of a single liner-equipped drainhole.

A patented U.S. Pat. No. 4,787,465 drilling and completion technique for multiple drainholes of ultra-short (ca. 10 ft) radius of curvature has also been used in such sandy reservoirs, but the liners of the short multiple drainholes are not tied-in to the vertical casing and their inner diameter and curvature radius are too small to allow the use of conventional logging and cleaning tools.

SUMMARY OF THE INVENTION

The present invention addresses the problem of drilling, cementation and tie-in by pressure-tight connections to a casing of twin or multiple drainholes of medium to short radius of curvature (typically 500 ft to 40 ft) equipped with liners of sufficient diameter to allow the passage of available well logging, perforating, cementing and cleaning tools, for subsequent well maintenance and repairs.

The next step is to provide the means to bring up the reservoir fluids and/or to inject fluids from the surface into the reservoir through the drainhole liners. Depending upon the mode of exploitation of the well and field conditions, a great variety of tubing completion assemblies may be used for these purposes. The simplest, which allows only commingled flow from or into all drainholes simultaneously, does not even requires any additional equipment if vertical flow is through the casing, but it provides minimum operational flexibility and no safety controls. For these reasons, additional equipment (at least a properly sized production tubing or a kill string for safety, for instance, and often a hanger or a packer) will be used in the field. The tubing completion assembly which provides the greatest operational flexibility and safety is that which provides a direct connection of each drainhole separately to a tubing, thus leaving the casing/tubing annulus available for other uses.

This is the type of tubing completion assembly which is included in the present invention. It also provides the means of implementing in this type of heterogeneous reservoirs the heavy oil recovery process and the injected steam quality conservation process described respectively in U.S. Pat. No. 4,706,751 and U.S. Pat. No. 5,085,275 using some of the equipment described in U.S. Pat. No. 5,052,482. The present invention, however, does not preclude the use of the already known simpler completion designs, whenever they are sufficient for the application considered. Known elements of downhole equipment (valve nipple joints, safety joints, retrievable plugs, etc. . .) may also be added, as needed, to the novel tubing completion assembly to perform specific additional tasks.

Some of the reservoirs under consideration, especially those containing heavy oil, require artificial lift to bring the production stream to the surface. The present invention includes equipment providing the means of pumping produced fluids and of injecting steam and/or other gases in such wells equipped with multiple drainholes completed with liners. Sand production being frequent in such reservoirs, the drainholes may be gravel packed or equipped with screens or subjected to known sand consolidation techniques.

The desired well and drainholes configuration may be obtained either with entirely new wells or by re-entry into an existing vertical cased well, in which case the required equipment and procedures are somewhat different.

In all cases it is intended to obtain leak-proof connections between the drainhole liners and the vertical casing and between the drainhole liners and the tubings used either for production, injection and pumping. The desirability of a system which can be installed in as few steps as possible and which can easily be disassembled during future work-over operations has led to develop downhole equipment and procedures, which conform with proven oil field safety practices.

Due to the complex nature of oil reservoirs, especially those made-up of clastic rocks deposited in agitated water (Fluvio-Deltaic environment, turbidite currents or near shore sedimentation) or those resulting from eolien transport (Dunes), the presence of various sediment heterogeneities and fractures, together with other reservoir engineering considerations regarding water/oil and gas/oil contacts locations, reservoir fluid pressure and solution GOR of the produced oil, will dictate various well and drainhole configurations.

Although the most frequently applicable is that of twin drainholes with their respective horizontal sections oriented at 180 degrees from each other, the equipment, tools and procedures which will be described are not restricted to that single configuration. It will become apparent to those skilled in the art that similar equipment and procedures may be adapted to all other multiple drainhole configurations without departing from the spirit of this invention.

Ranked in increasing degrees of complexity, the cases of drilling, tie-in and completion of new wells include:

1) side by side drainholes kicked-off from the bottom of a vertical cased well, using a twin whipstock,

2) side by side drainholes connected by intermediate liners to the bottom of a vertical well,

3) side by side drainholes obtained from a deviated cased well,

4) stacked drainholes kicked-off one above the other from a new vertical cased well. Two different tie-in methods and

equipment types will be described, one using telescopic liner stubs and telescopic connector tubes to tie-in and complete the well, the other using intermediate cemented liners and articulated connector tubes.

5) use of a single pump for both drainholes, located above the kick-off points,

6) conveyance of low GOR production streams from each drainhole through a syphon to a single pump located near the base of an oil sump well below the kick-off points,

7) pumping of each drainhole with a pump located at or near the start of the horizontal segment,

8) simultaneous injection of steam and/or gases into one drainhole while producing oil and water from the other drainhole, as taught in in U.S. Pat. Nos. 4,706,751 and in application No. 512,317, now U.S. Pat. No. 5,085,275.

For re-entry into an existing vertical cased well, modified equipment and procedures will be described, corresponding to cases similar to cases 1, 2, 4, 6, 7 and 8 above.

DR BRIEF DESCRIPTION OF DRAWINGS

FIG. 1 is a vertical cross section of the special casing joint with twin whipstocks used in Case 1.

FIG. 1*a* is a perspective drawing showing the base of the retrievable top whipstock of Case 1.

FIG. 1*b* is a vertical cross section showing the drainhole tie-in to the casing.

FIG. 1*c* is a vertical cross section showing the tubing completion.

Subb ~~FIG. 1d is a vertical cross section of an overshot-type tool used in case 1.~~

FIG. 2 ~~and~~ 2*a* are vertical cross sections showing schematically the successive phases of the operations required in Case 2.

FIG. 2*b* is a vertical cross section of the spherical seal union joint used in Case 2 and in subsequent cases.

FIG. 2*c* is a schematic vertical cross section of a hydraulically operated tool for punching multiple slots into thin gauge liners.

FIG. 2*d* is a schematic vertical cross section of the tubing completion assembly used in Case 2.

Canceled 171 [FIG. 3 is a vertical cross section of a special casing joint equipped with a drillable packer and retrievable whipstock for drilling and completion of the side-tracked hole of Case 3.] 173

FIG. 3*a* is a vertical cross section of an intermediate liner.

FIG. 3*b* is a vertical cross section of the deviated cased well and side-tracked hole of Case 3.

FIG. 3*c* is a vertical cross-section of the overshot-type tool used in Case 3.

FIG. 4 is a vertical cross section showing the special casing joint with its stub extended and cemented in the reamed cavity of Case 4.

FIG. 4*a* is a vertical cross section showing connection to the stubs by means of articulated connector tubes.

FIG. 4*b* is a schematic flow diagram showing the connection to the stubs by means of telescopic connector tubes.

FIG. 4*c* and 4*d* are vertical cross sections showing telescopic connector tubes respectively in the retracted and in the extended positions.

FIG. 4*e* is a schematic vertical cross section showing the tubing completion assembly for two pairs of stacked drainholes in Case 4.

FIG. 5*a*, 5*b* and 5*c* are schematic vertical cross sections of a well and twin drainholes, showing different possible pump locations.

171 [FIG. 6 is a schematic vertical cross section of a well and two drainholes, showing the various fluid levels in the reservoir.] 173 Canceled

FIG. 6*a* is a schematic diagram showing the operation of the periodic gas purging system.

FIG. 6*b* is a cross section of the permselective plug and venturi used for continuous gas purging.

FIG. 7 is a vertical cross section of the tubing completion assembly used for dual pumps in Case 7.

FIG. 8 and 8*a* are vertical cross sections of the tubing completion assembly used for Case 8, with the well tie-in configuration of Case 1.

FIG. 9 and 9*a* are vertical cross sections of the special casing insert of Case 1*a* and 3*a* respectively.

FIG. 10 is a vertical cross section of the special casing patch with telescopic stubs used in Case 4*a*.

FIG. 11 is a schematic vertical cross section of the novel casing patch used for side-tracking and cementing intermediate liners in case 4*a* (second embodiment).

FIG. 12 is a schematic vertical cross section of the tubing completion assembly including two articulated connector tubes for Case 8*a* when an oil sump is used.

FIG. 13 is a schematic vertical cross section of the upper part of the tubing completion assembly for "huff and puff" steam injection of Cases 8 or 8*a* when dual pumps and a 4 string hanger are used.

DE DETAILED DESCRIPTION OF THE INVENTION

CASE 1 (TWIN WHIPSTOCK)

In Case 1 a vertical well is drilled to a depth slightly greater than that of the common kick-off depth of the drainholes. The casing string is made-up by including a special joint immediately above the conventional casing shoe and float collar. This casing joint shown on FIG. 1 includes two elliptical windows (1) machined at the desired kick-off angle, typically about 2 degrees oriented downward from the vertical.

These windows are plugged up with a drillable material (an Aluminum plate (2), for instance) machined to conform with the cylindrical surfaces of the casing. A twin whipstock (3), of hardened metal, is securely fastened to the casing joint, for instance by welding. It provides a curved guiding path from a guide plate above to each of the two plugged windows. For added strength, a portion of that curved guide may be partly filled with cement (4) or other drillable material. The guide plate (5), on top of the whipstock, presents four vertical cylindrical holes, two of them (6) of a diameter larger than that of the drainholes and two of them smaller. One of the smaller holes (7) in the guide plate (5) is threaded and extends to the whipstock base, to provide a flow path to the float collar and shoe below it. During cementing operations, the work string will be stabbed into the threaded connection to inject the cement slurry into the float collar and shoe and from there into the annular space behind the casing. The other small cylindrical hole has a smooth bore. Its function is to receive one of the alignment pins (8) used to positions and latch a retrievable whipstock top which provides a continuation of the guiding path from one of the two large holes to the casing side. The combi-

nation of the permanent twin whipstock with its retrievable top provides a guide to the drainhole drilling bit through the machined window. A perspective view of the retrievable top whipstock showing its two alignment pins (**8**) is presented on FIG. **1***a.*

When the first drainhole has been drilled to its total measured depth, the same whipstock (top and bottom parts) guides the liner into the drainhole. The liner, in the horizontal part, may be a slotted liner equipped with screens for gravel packing or it may be cemented and later selectively perforated. In all cases, however, the curved part of the liner is cemented using known procedures. The tail end of the liner is centered and hung into the open large vertical hole in the bottom whipstock (FIG. **1***b*), by means of a known hydraulically-set hanger (**9**) equipped with dual sets of slips and pressure-setting seals. It is terminated by the female part of a polished bore receptacle (**10**), which connects the liner to the work string used to run-in and cement the liner. When the cement has set, the work string is disconnected, a recess in the top whipstock is latched into hooks in an overshot tool, pulled up and rotated by 180 degrees for presentation and insertion of the two alignment pins (or prongs) respectively into each alternate small hole in the permanent whipstock. The overshot tool is then released and pulled out.

Drilling of the cement and plug in the second window now begins the drilling and liner cementing operations for the second drainhole, using the same procedures. With the liner hung and sealed in the second large vertical hole in the permanent whipstock, the work string is disconnected from the second polished bore receptacle. The top whipstock is latched with an overshot tool and pulled out of the well. This completes the drainholes drilling and tie-in operations.

Completion of the well (see FIG. **1***c*) is achieved by making up and running-in a tubing string consisting of dual tubing prongs (**11**) equipped with chevron seals (**12**) and connected to the lower ends of an inverted Y nipple joint (**13**). The chevron seals constitute the male mating parts of the two polished bore receptacles (**10**) previously installed. The upper branch of the inverted Y nipple joint (**13**) is connected to a conventional tubing hanger (**14**) which may be set hydraulically or by wireline. The tubing string (**15**) is oriented so as to stab the tubing prongs into the female parts of the two polished bore receptacles. After leak-testing of the sealed connections, the tubing hanger is set and the wellhead is nippled up using conventional equipment and procedures.

If the well is not naturally flowing, artificial lift equipment may also be included in the tubing string, such as gas lift valves, diverter valves, a pump seat nipple, etc. . . in the manner which is familiar to those skilled in the art of oil well completion.

CASE 2 (TWIN DEVIATED HOLES)

In Case **2**, from a vertical cased well drilled and cemented by conventional techniques, the casing shoe is drilled out and two short (ca. 50 ft long) smaller diameter twin deviated holes are drilled through the bottom of the vertical well. This uses, for instance, a bit (**16**) driven by a downhole motor (**17**) connected to a bent sub (**18**), in the type of downhole assembly commonly used for drilling horizontal wells (see FIG. **2**).

With deviation angles of only a few degrees from the vertical, the separation between the two holes is only of a few feet at the bottom and of a few inches at the top. Consequently, it may be advantageous in some formations, to start the drilling operation by first under-reaming a single large-diameter short hole below the casing shoe, from which the twin small-diameter drainholes are then started, with opposite orientations. Several other available techniques are also familiar to those skilled in the art of drilling oil wells and may be used to achieve the same result.

Two short (ca. 60 ft long) intermediate liners (**19**), (**20**) are run in and sealed one in each of the deviated holes. The cementing operation uses Furan or other known heat-hardened resin/cement slurries as seal. It may be performed in a single trip by making-up and running-in at the end of the work string an assembly including, as shown in FIG. **2***a:*

an inverted Y tubing nipple (**13**),

two spherical seal articulated union joints (**21**), one at each end of the two branches of the inverted Y nipple,

two liner releasing tools (**22**) equipped with a tail pipe, one for each intermediate liner string. Each tailpipe (**23**) is fitted with a cup-type packer (**24**), which closes the annular space between liner and tailpipe during cement injection and displacement behind the liner, but opens during the reverse circulation of mud, for cleaning after the liners have been released from their respective latching tool. The cementing string with its two tailpipes is then pulled out.

FIG. **2***b* shows in detail the spring-loaded spherical seal articulated joint (**21**).

After this cementing operation, the vertical casing is thus tied-in and sealed to each intermediate liner over an overlap interval of about 10 ft. Entry to one of the liners is closed by a temporary plug set by wireline and drilling of a drainhole proceeds through the other intermediate liner, using a bit driven by a conventional downhole motor and bent sub assembly.

After reaching total measured depth, a smaller diameter liner is run-in, hung into the lower part of the intermediate liner and cemented at least from the intermediate liner to the start of the horizontal segment of the drainhole. An alternate method is to use a coiled tubing as drill string and to abandon the bit and motor in the hole, prior to cementing it as a liner. Gravel packing and/or sand consolidation techniques may be used. The lower part of the liner may be slotted and equipped with screens. Otherwise, this part of the liner may be cemented and selectively perforated using known perforating guns.

In view of the relatively small diameter of the liner (typically less than 2.5 in.), a thin-gauged coiled tubing is preferred as liner.

The annular space behind the liner may be gravel packed first by displacement of a sand slurry, in direct circulation, followed by a reverse circulation of the sand slurry. After cementing the upper part of the coiled tubing liner, its lower part is mechanically slotted by running through it, on a smaller diameter coiled tubing, a hydraulically actuated punching tool in which multiple articulated edge-cutting wheels (**25**) or punches are periodically pressed against the inner surface of the liner to punch slots into the coiled tubing liner, thus opening flow paths to the gravel packed annulus. FIG. **2***c* shows a schematic view of the hydraulic punching tool. Sand consolidation by injection of a suitable thermosetting resin as a mist in a hot gas or steam or as a suspension or foam in a liquid may then be applied to the gravel pack and cross-linked to stabilize it, with minimum permeability reduction.

After removal of the temporary plug in the second intermediate liner, the same procedures are used to drill, gravel pack, cement, and selectively perforate the second drainhole, thus completing all drilling and tie-in operations for

both drainholes.

Well completion is achieved by make-up, run-in and set of the production tubing string assembly, shown on FIG. 2*d*. It consists of a tubing connected to:

a conventional hanger (14), an inverted Y nipple joint (13) with each of its two lower branches equipped with a spherical seal union joint (21) and a connector tube (26) equipped, near its end, with a conventional packer (27) of the type which can be set hydraulically or by wireline.

The tubing is oriented so that the tail end of each connector tube penetrates into the upper part of one of the cemented intermediate liners while rotating slightly around the articulation formed by its union joint. A spreader spring, (28) linked to the upper part of each articulated tube facilitates its insertion into the corresponding drainhole liner.

Each of the packers is then set, to tie-in each articulated connector tube to its corresponding intermediate liner. After leak-testing, the tubing hanger is then set and the well head nippled up. Again, suitable known artificial lift equipment components may have been included in the tubing string, if it is expected that the well will not be flowing at an economic rate without gas-lift or pumping.

CASE 3 (DEVIATED CASED WELL)

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In Case 3, a vertical well is drilled, with its lower 50 ft deviated at the angle required to kick-off a horizontal drainhole and oriented in the direction selected for the drainholes. A special casing string is made-up, run-in and cemented by known techniques into the vertical and deviated portions of the hole. It consits of a shoe, a float collar and a special casing joint (FIG. 3) located at a depth slightly above that of the start of the hole deviation. This casing joint presents an elliptical window machined into the casing with a downward orientation of a few degrees from the vertical. The window (1) is again plugged off with a drillable plate (2) made, for instance, of a soft metal and shaped to generally conform with the casing surfaces. The plug is firmly attached to the casing by means of drillable fasteners (29). Its orientation is also indicated by a vertical drillable key or groove (30) in the casing joint inner surface at or near its lower end.

After displacing the cement slurry behind the casing, the string is rotated to orient the plugged window in the direction opposite to that of the deviated portion of the hole. This is done by marking the window direction on all the uphole joints of the casing, up to the rig floor. After the cement has set, a whipstock drillable packer (31) is run-in and set below the special casing joint at a predetermined depth. A retrievable whipstock (32) is then oriented towards the plugged window, using the casing joint's orientation key or groove, fitted in a matching groove or key in the whipstock's outer cylindrical surface. The oriented whipstock presents a curved guiding surface which matches the depth, width and orientation of the window, so that a side-tracked hole (33) of diameter smaller than the casing ID may be kicked-off by drilling the window plug. The hollowed curve of the whipstock also presents a central alignment groove (34) corresponding to the lowest point of the elliptical window (1). The base of the whipstock is preferably equipped with a rubber cup for catching excess cement during later operations.

After drilling out the plug and drilling a side-tracked hole through the window, to a depth of about 60 ft, an intermediate liner is run-in through the window and cemented by known techniques. The upper end of the liner has been machined as shown on FIG. 3*a* so as to conform with the inner edge of the window (1) and its edge is equipped with an elliptical collar (35) made of drillable metal, which conforms with the inner surface of the casing at the window's edge. The outer surface of the collar is covered with a rubber gasket or plastic sealing material (36) and the lowest part of the collar presents a key (37) which matches the central alignment groove (34) in the retrievable whipstock, so that the intermediate liner end may be oriented and guided to provide a closely fitting contact between the drillable elliptical collar and the casing window's edge. The intermediate liner is equipped with a cementing shoe and latched to a liner releasing tool equipped with a tailpipe and a cup-type packer for cementing by the same technique as in Case 2. After displacement of the cement slurry behind the liner, a ball or plug is dropped to close the shoe and casing mud pressure is increased to firmly apply the drillable collar against the inner surface of the casing, while reverse circulation is established through the tailpipe to remove any excess cement.

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After the cement has set and the cementing string has been pulled out, the outer saw-tooth grooves (38) of the whipstock are latched into an overshot tool equipped with a milling edge to drill out the elliptical collar (35) and the whipstock is pulled out. The supporting whipstock packer (31) is also drilled out and pulled out with the overshot milling tool, which also is equipped at its lower end with a suitable packer-latching device. These operations leave full openings in both the deviated casing and the side-tracked intermediate liner. Both of them provide a relatively large deviated casing and a slightly smaller liner to be used as the respective starting points of two drainholes, in the same way as in Case 2, but the drainhole diameters and that of their respective liners may be greater than that of Cases 1 or 2.

Liner gravel packing, cementation and liner hanging respectively in the deviated casing and in the side-tracked intermediate liner may be done either as in Case 1 or as in Case 2, depending upon the drainhole diameter.

Well completion is done as in Case 2, except that the tie-in of the articulated connector tubes may be obtained either with packers, as in Case 2 or with polished bore receptacles, and seals as in Case 1.

CASE 4 (STACKED DRAINHOLES)

In Case 4 the drainholes are stacked, one above the other, so that the full diameter of the casing is available as a starting point for each drainhole. Here again, a special casing joint (or joints) now presenting two elliptical windows at two different depths and oriented with opposite bearings, is included in the casing string during make-up to provide the starting points of the drainholes.

In a first embodiment (FIG. 4), the drillable plugs closing the windows during run-in are located at the ends of telescopic liner stubs (39) oriented downward at the kick-off angle (typically 2 degrees). Each plugged stub is later hydraulically extended into an under-reamed portion (40) of the vertical hole filled with cement slurry during the casing cementation, to serve as guide for a bit driven by a downhole motor connected to a bent sub in a conventional drilling assembly. Each of these two stubs is supported during run-in and guided during its outwards extension by two tubular guides or cages made of drillable metal. One of them (41) is fixed, it is attached to the casing by drillable metal fasteners. The other (42) is mobile and slides within the fixed cage (41) over only half of the stub extension, while providing a

cantilevered sliding internal support to the extended stub. The upper end of the stub is terminated by a drillable collar (35) and gasket (37) as in Case 3.

For 7 in. OD liner stubs at a 2 degree angle in a 9⅝ in. OD casing the elliptical casing window would be 200.6 in. by 7 in. For a 30 in. ID reamed cavity, the total stub extension length is about 286.6 in. and the stub maximum length is about 487.2 in. This is because both ends of the stub are machined to conform with the elliptical window, leaving in the middle a length of about 86 in. of tubular segment. This length is sufficient to provide tie-in both with the cemented drainhole liner and also with a connector tube linked to the tubing. With the vertical casing and extended stubs cemented, drilling of the extension guides and other internals leaves two 7 in. OD stubs as pockets from which to start drilling the drainholes, using the usual bent sub and downhole motor assembly including the navigation system for angle build up and directional control. The first step is to drill out the stub's end plug. After reaching total measured depth, a liner assembly is made-up and run-in through the stub. Gravel packing and cementing of the uphole liner proceed as in Case 1. The upper end of the liner is centered and hung into the lower part of the stub. It is also terminated by the female part of a polished bore receptacle. The work string is disconnected from the polished bore receptacle and pulled out. The same operations are repeated for the second drainhole, leaving the well ready for tubing completion.

The tubing completion assembly, shown on FIG. 4*a*, again includes a tubing hanger (14), an inverted Y nipple joint (13), two spherical seal union joints (21), each terminated by a connector tube stinger equipped with chevron seals (12). A bow spring (28) between the two stingers facilitates their entry into the stubs where they are mated with their respective polished bore receptacle (10). After leak testing of the connections, the tubing hanger is set and the well head nippled up, as in Case 3. The bow spring may be compressed during run-in and released by a suitable wireline tool when reaching the proper insertion depth for the connector tubes. This provision is especially useful when simultaneously connecting more than two connector tubes. In another embodiment, shown on FIG. 4*b*, connection of the tubing to the drainholes is by means of telescopic connector tubes (43). These are located in cylindrical cavities (44), connected to the two vertical lower branches of the inverted Y nipple joint (13) at the kick-off angle. The lower end of each connector tube (43) is equipped with chevron seals (12), supplemented in some cases by an end to end spherical metal/metal seal (45). A spring (47) triggered from the surface by hydraulic or wireline means strongly applies the extended connector tube's spherical end against a corresponding spherical cavity forming the bottom of the polished bore receptacle (10) to provide this metal/metal seal. In FIG. 4*c*, the connector tube is locked into its extended position, but may be retracted inside the cylinder body by shearing off the latch pins (46) with a wireline tool as shown in FIG. 4*d*, when it is necessary to disconnect and pull out the tubing for a well work-over. The upper end of the body (44) is equipped with dogs which bite into the inner surface of the casing when the telescopic connector tube is fully extended and pressed against the bottom of the polished bore receptacle. It will be apparent to those skilled in the art that this is only one of many possible ways of achieving both a spring-loaded metal/metal seal and anchoring in the extended position of the telescopic tube while providing means for its eventual retraction and pull out. The invention is not limited to the example described herein.

In yet another embodiment, the casing includes two special joints of the type used in Case 3, located one above the other, separated by an interval sufficient for setting a packer and the two plugged windows oriented in opposite directions. Again, as in Case 3, a drillable whipstock packer is set below one of the windows. The retrievable whipstock is latched into the packer and drilling of the window and side-tracked hole proceeds. A short intermediate liner, as in Case 3, is run-in through the window and cemented. The procedure, repeated for both windows, leaves two side-tracked intermediate liners from which the drainholes are drilled, and their liners are hung and cemented. After drilling out the drillable elliptical collar of each cemented intermediate liner, the entire casing space is available for installing the tubing completion assembly.

The previous embodiments which leave full access to the stacked drainholes also allow to drill, gravel-pack, and tie-in any number of drainholes, equipped with cemented liners, one above the other, by using as many stubs or intermediate liners as there are drainholes.

The commingled production from all drainholes may be discharged into an oil sump formed by the casing below a production packer and pumped to the surface through a single production tubing. The pump location in the tubing may be above the packer, or below it in a tailpipe tubing extension. With such a simple tubing completion assembly, the access into each of the drainholes of logging or cleaning tools is obtained by means of a suitable kick-over tool of known design.

The tubing completion assembly may also be the same as in Cases 2 and 3, which provide a continuous path from the surface to each of two twin drainholes, and greater operational flexibility.

The types of tubing completion assemblies including telescopic connector tubes or articulated connector tubes, described above for two stacked drainholes, are also applicable to more than two stacked drainholes. If the drainholes are grouped by pairs, connected to a single production tubing, the number of parallel tubes in the casing at any depth is reduced to only three, as shown on FIG. 4*e*. These are:

the two tubings connected to the lower branches of the inverted Y nipple joint (13), for a given pair of drainholes,

the production tubing extension (48) leading to the other drainhole pairs below the first one.

This number may be increased to four if the hydraulic or jet pump is located below the top pair of drainholes and if the tubing carrying the power fluid to the pump is parallel with the production tubing, but the number of possible stacked drainholes, which is only limited by the casing length, may be much greater.

CASE 5 (ARTIFICIAL LIFT)

In all previous cases, it was assumed that reservoir pressure and produced gas expansion are sufficient to convey the production stream to the surface, or at least up the curved portion of each drainhole (up to 500 ft high) without excessive reduction of the total pressure draw down, so that a single artificial lift system providing suction at the base of the production tubing can be used for both drainholes. This may be a conventional gas-lift valve supplied with compressed gas through the casing/tubing annulus. Conversely, the production stream may be conveyed to the surface through the annulus while lift gas is supplied through the tubing. In that event, a packer must be added to the tubing hanger, a diverter valve must be included in the tubing above

(6)

the packer to convey the production stream to the annulus and a plug must be located in the tubing between the open diverter valve and the bottom gas-lift valve.

Similarly, the commingled production stream from both drainholes may be pumped to the surface through the tubing or through the annulus using known types of pumps. These can be mechanically actuated by sucking rods, by rotating rods (progressive cavity pumps) or they can be actuated hydraulically. Jet pumps may also be used as well as electrically driven submersible pumps. Pump selection criteria and the importance of an optimum depth of the pump in the well are well known from those skilled in the art. The pump may be anchored either in the tubing or in the annulus, depending upon reservoir and well conditions, including the need to handle gas or sand production.

It is one of the main advantages of connecting two or more drainholes to a single vertical well to allow the possibilty of using a single pump (49) as in FIG. 5*a* for all the drainholes, thus reducing capital and operating costs of pumping the production stream.

It will be shown later that this possibility is, however, limited in the case of some under-pressured reservoirs. Well completion equipment and novel assembly procedures have been developed to extend the possibility of using a single pump by locating it, as in FIG. 5*b*, below the drainholes kick-off points. Finally, special equipment and methods are described for the installation and use of a pump in each drainhole, if necessary, as in FIG. 5*c*.

These considerations on artificial lift are equally applicable to new wells and to the re-entry into an existing casing, to vertical as well as to deviated cased wells.

CASE 6 (FLOW THROUGH A SYPHON)

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In under-pressured reservoirs containing low GOR oil, reservoir energy may be insufficient to convey the production stream up to a pump or gas lift valve located above the kick-off points of the drainholes. The difference in elevation between such a pump and the fluids entry points in the horizontal part of the drainholes is greater than the drainholes radius of curvature, which may be up to 500 ft. In addition, there are significant friction pressure drops through the horizontal and curved portions of small-diameter liners, which may reduce the calculated net flowing fluid head at the pump (49) inlet to a value below the required minimum NPSH of the pump. This indicates that cavitation is likely to occur in the pump, with highly detrimental erosion effects and a reduced flowrate. To alleviate this problem, flow from each drainhole may be directed to an oil sump (50), with the pump taking suction at or near the bottom of the sump. The top of the sump is closed by a packer (51) a short distance above the highest kick-off point. It constitutes the apex of a kind of syphon (see FIG. 6) for each drainhole. For very low GOR oil, frequently present in under-pressured mature reservoirs, the flowing pressure at that point may still be well above the bubble point of the production stream, so that the risk of cavitation and break-up of the de-celerating liquid stream at that point is much less than it would be in a pump at the same location. The flowing pressure at the apex, plus the liquid head in the sump, provide a pump suction pressure exceeding the minimum NPSH required, thus eliminating the risk of cavitation in the bottom pump.

Instead of a pump, an intermittent flow gas lift system may also be used for the same purpose. In this known system, a gas piston lifts an oil slug up the tubing after the standing valve at the bottom has closed. This is equivalent to a beam pump, but more tolerant of sand production.

The drilling and tie-in equipment and procedures are the same as in Cases 1, 2, and 4, except that a sump is drilled and cased vertically below the lowest kick-off point. In Cases 1 and 4, that sump may be created by placing the special casing joint well above the casing shoe.

For the Case 1 configuration, the casing joint shown previously on FIG. 1 is modified as follows:

1) The threaded small hole (7) in the bottom twin whipstock of Case 1 is extended below with a tailpipe which is used first to bring the cement slurry to the shoe, during casing cementation. The bottom part of the tail pipe also includes a pump latching nipple joint.

The threaded small hole is also extended above with the female part of a polished bore receptacle to later receive a tubing stinger equipped with chevron seals, so as to extend the tailpipe upwards by a production tubing through a sealing connection.

2) The smooth bore second small hole is drilled through the bottom whipstock, to provide a flow path for the produced fluids into the oil sump below it. It may be supplemented with other small holes to provide a sufficiently large cross section for the low velocity liquid flow in the downward leg of the syphon.

The polished bore receptacles terminating the cemented drainhole liners may be omitted, the large vertical holes providing a natural guide for inserting logging or cleaning tools into the liners.

In addition, the tubing completion assembly is modified to consist of:

a) a production tubing,

b) a dual string production packer, with a retrievable plug in its short string. The main purpose of that string is to provide eventual access to the sump for inserting logging or cleaning tools into the drainholes below the packer. A secondary purpose of the short string is to provide a pump by-pass flow path which may be periodically opened to let any gas accumulation below the packer escape upwards by buoyancy, while re-filling the sump with de-gassed liquid from above the packer to maintain continuity of the liquid stream through the syphon. Periodic gas purging operations may be automatically controlled from the surface. For that purpose, the retrievable plug in the short string is in fact a conventional wireline retrievable subsurface safety valve (FIG. 6*a*), in a normally closed position but operated by known hydraulic or electrical means whenever the presence of a small gas cap is detected below the packer. Detection means may be direct, using known liquid level sensors or indirect, by continuous monitoring of the pump efficiency. Continuous gas purging may otherwise be obtained by using a wireline plug including a permselective membrane (52), which allows continuous diffusional gas migration upwards, under a gas pressure gradient across the membrane, created by a retrievable venturi (53), located at the exit of the production tubing into the larger cross section of the casing annular space. The membrane also prevents liquid flow downwards (see FIG. 6*b*). In this system, the energy supplied to the pump serves three purposes:

1) to bring the gas-free liquid stream from the pump to a point above the packer, and

2) to operate a sort of gas ejector pump to re-mix the produced gas with the liquid stream in the casing/tubing annulus, above the packer.

3) to lift the mixed liquid and gas stream up the casing/tubing annulus to the separator.

Suitable permselective plug materials include, but are not limited to: charcoal, agglomerated carbon black, compressed powdered mineral adsorbents, asbestos felt, etc. . .

The long string, in the dual string packer, extends below the packer with a stinger equipped with chevron seals which is stabbed into the polished bore receptacle threaded into the top of the small hole (7) of the modified novel casing joint, thus providing a connection from the production tubing to the tailpipe, in which a pump is set.

A rod string or a power fluid tubing string is then inserted from the surface within the production tubing and connected to the pump.

In this configuration, the flow from both drainholes is discharged into the sump below the packer and flows downwards through one or several holes in the whipstock, to reach the pump inlet at the bottom of the tailpipe, to be discharged, at a higher pressure, into the production tubing and from it to the casing annulus leading to the surface.

In cases where the cased well effluent flows into a very low pressure separator, the packer may be omitted if the production tubing extends to the surface, so that any gas coming out of solution at the apex of the syphon freely accumulates in the casing/tubing annulus, forming a low pressure gas cap extending up to the casing head. Gas purging of the casing to maintain the gas cap at the required low pressure is then accomplished through a conventional gas re-mixing valve at the surface, upstream of the low pressure separator inlet.

In the configuration of Case 2, after drilling and tie-in of the twin drainholes, a third hole is drilled vertically and its liner is cemented to provide the oil sump. The tubing completion assembly now consists only of a production tubing, a dual string packer with its short string again closed with a retrievable gas-purging plug and the production tubing and pump extending below the packer for insertion into the sump.

In the configuration of Case 4, the casing now extends below the special joint (or joints) to form the oil sump. The tubing completion assembly is the same as above: a production tubing, a dual string packer with its short string temporarily plugged off and the production tubing extending below the packer, with a bottom pump.

CASE 7 (DUAL PUMPING)

In low pressure reservoirs containing relatively high GOR oil, the risk of cavitation at the apex of the syphon may be too great, so that the use of a syphon is no longer possible. In some very heterogeneous reservoirs, it is also possible that the productivity indices of the two drainholes are widely different. In those cases, it is preferable to equip each drainhole with its own pump sized to maximize total oil production. The same is true if one of the drainholes is more prone to gas coning or water coning than the other.

Progressive cavity pumps driven by rotating rods and hydraulic or jet pumps driven by power fluid operate satisfactorily in highly deviated wells. A pump anchor nipple joint is included in the liner string, at the selected depth in the curved portion of each drainhole. The production tubing diameter must be increased to provide space inside it for the power fluid tubing strings or for the rotating rod strings. Another alternative is to insert the power fluid tubing or the rotating rod string into the drainhole liner through a side entry in each of the lower branches of the inverted Y nipple joint. In that case (see FIG. 7), a short conduit (54) leads from the top of the tubing hanger (or packer) to the side entry point to facilitate the insertion of the power fluid tubing or rod string from the annulus space into the drainhole liner. This requires corresponding modifications of the Y nipple joint (13) and of the tubing hanger (14), or packer (51).

CASE 8 ("HUFF AND PUFF" MODE OF OPERATION)

In heavy oil reservoirs, it is advantageous to operate the twin drainholes in sequential "huff and puff" steam injection, in which one drainhole is under injection while the other is under production. For surface-generated steam, the production tubing may be replaced by an insulated steam tubing. A downhole three-way retrievable valve of the type described and claimed in U.S. Pat. No. 5,052,482 is required in each lower tubing branch below the inverted Y nipple joint. This is done (FIG. 8 and 8*a*) by adding a valve nipple joint (55) in each branch with its control hydraulic line (56), strapped on the outer surface of the insulated steam tubing (57). In its axial full opening position, the valve conveys steam from the tubing to the corresponding drainhole. In its side opening position, the valve discharges the production stream from the drainhole liner into the casing annulus space. From there, the produced fluid may be pumped to the surface or gas-lifted.

The same well completion type is also applicable to reservoirs subjected to "huff and puff" injection of solvent gases, such as CO_2, which are known to also reduce oil viscosity, but to a lesser degree than steam injection. In such cases, artificial lift of the produced fluids may be unnecessary.

If the reservoir pressure and/or produced GOR are sufficient to bring the oil up to the kick-off point of each drainhole, the pump is hung in the annulus casing/steam tubing, above the kick-off points.

If, however, the heavy oil reservoir is also under-pressured, as, for instance in California's Midway Sunset field, the pump may be located at the bottom of an oil sump as in Case 6 or it may be located within each drainhole liner as in Case 7. The tubing completion will be modified accordingly, as will be shown later. The type of pump used in that case must allow easy disconnection from its seat, when the drainhole is switched from the production mode to the injection mode. For this reason, jet pumps, hydraulic pumps and progressive cavity pumps are preferred in that case.

For under-pressured heavy oil reservoirs in which the drainhole production flows through a syphon (Case 6), the tubing completion assembly in which telescopic or articulated connector tubes are used to connect the steam tubing to the drainholes, the packer may be a three or four string packer, depending upon the location of the inverted Y nipple joint with respect to the packer. With the Y nipple joint below the packer, only three strings are connected to the bottom face of the packer:the upper branch of the Y, the production tubing extending into the oil sump and the short string with its retrievable plug. To increase the packer depth, and, correspondingly that of the apex of the syphon, the inverted Y nipple joint is located above a four string packer, in which two of the strings are connected to the lower branches of the inverted Y, the third string is connected to the production tubing extending into the oil sump and the fourth string is the temporarily plugged-off pump by-pass. The production tubing may end just above the packer without reaching the surface, if the production stream flows through the casing/steam tubing annulus.

With steam generated downhole, together with permanent

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gases (CH4, H2) using the equipment described and claimed in U.S. Pat. No. 5,052,482, it is preferable to inject the steam and gases through the side opening of the downhole three-way valve into one drainhole, while conveying the production stream from the other drainhole to the central production tubing through the axial full opening of its downhole valve. The equipment and procedures for drilling, gravel packing, cementation, tie-in of multiple drainholes and for their tubing completion, previously described, are also applicable with some minor modifications which will be indicated later.

It will be apparent to those skilled in the art of oil well design that it is not possible to cover all the situations encountered in all reservoirs, because of their infinite diversity, but that the equipment and procedures described herein lend themselves to a very large number of combinations and permutations, which are capable of addressing most situations in which multiple horizontal drainholes may be advantageously used. Such combinations and permutations, which are obvious to those skilled in the art, do not detract from the spirit of the present invention and are included in it.

RE-ENTRY INTO AN EXISTING CASED WELL (WORK-OVER)

The cost of drilling and cementing the vertical cased well is a large portion of the total cost of a well presenting the general configurations described above. Re-entry into an existing cased well for drilling, gravel-packing, cementation and liner tie-in of multiple drainholes is a cost-effective way of increasing productivity.

If the existing cased well already presents a suitable deviation for the use of Case 3 procedures, the absence of a pre-established window in the casing string may be remedied by milling a side-track window using available tapered mills guided by the novel retrievable whipstock latched in a drillable whipstock packer set slightly above the deviation depth. The procedures and equipment, other than the special casing joint, are then the same as in Case **3**, provided that known downhole orientation surveying methods are used to remedy the absence of pre-determined alignment keys or grooves in the casing.

In most fields, however, the existing casing will be essentially vertical, so Cases **1**, **2**, **4**, **6**, **7** and **8** will be more relevant.

CASE 1*a* (TWIN WHIPSTOCK INSERT)

The procedures of Case **1** may be used if a twin whipstock insert of diameter less than the drift diameter of the existing casing is run-in, hung in the casing and cemented at the selected depth above a plug permanently set in the casing. The oriented insert (FIG. **9**), is held by a known packer/hanger (**58**) set hydraulically or by wireline tools. The hanger's slips are preferably located in the lower part of the insert below the drainholes so as to avoid any interference with them. Here again, elliptical windows will be milled in the existing casing using tapered mills guided by the twin whipstock (**3**).

In another embodiment (FIG. **9***a*), the hanger slips are located above the twin whipstock, so that the casing may be entirely milled over the depth interval of the windows, covered by the twin whipstock (**3**).

CASE 2*a* (TWIN DEVIATED HOLES THROUGH MILLED CASING INTERVAL)

The plugged casing is milled over an interval sufficient to drill the sidetracked starting holes of Case **2** (FIG. **9***a*). Starting of the holes with a bent sub/downhole motor assembly may again be facilitated by first under-reaming that interval. Following these preliminary operations, the work proceeds as in Case **2**, using the same equipment, tools and procedures. It will be apparent to those skilled in the art that the use of coiled tubings as liners and their subsequent in-situ mechanical slotting are equally applicable to any other case.

CASE 4*a* (STACKED DRAINHOLES IN MILLED CASING)

The existing casing is milled out and the hole is under-reamed to a diameter of about 30 in. over the depth intervals corresponding respectively to each drainhole start. A casing patch is then run-in and fastened to the casing by means of hanger slips (**59**) above and below the lower milled-out interval. This embodiment is shown on FIG. **10**.

The casing patch presents close similarities with the special casing joint of Case **4**, except that its outside diameter must be less than the drift diameter of the existing casing and that its outer surface, opposite the plugged telescopic stub (**39**) is now covered by an external rubber packer (**60**), which, when inflated with cement slurry entirely fills the reamed cavity. A suitable device including shearing disks also allows to inject the cement slurry in the two overlap (**61**) annular spaces between casing and casing patch hangers (**14**) above and below the cement-filled bladder, during the hydraulically-controlled extension of the stub into the slurry filling the rubber bladder. As in Case **4**, the stub (**39**) is supported and guided during its extension by a fixed guiding cage (**41**) and a mobile inner guide (**42**) which penetrates only half way outside the casing. Added support and guidance is also provided by several cables (**62**) attached to the rubber wall and pulled under hydraulically-controlled tension from a drillable drum (**63**) through inclined holes (**64**) in the casing patch wall, at various locations around the machined edge of the elliptical window (**1**) through which the stub is extended.

With the rubber bladder fully inflated and pressed against the reamed cavity wall (**40**), the taught cables provide additional guidance and support to the stub (**39**) in its fully extended position. The drillable guides and the tail-end drillable collar (**35**) of the stub are drilled-out after the cement has set. This restores the vertical cased well to a diameter equal to that of the casing patch drift diameter.

A second casing patch is run-in, oriented, hung and cemented, with full extension of the second stub into the upper reamed interval, thus providing the start for the second drainhole.

Drilling, gravel packing, liner hanging and cementing procedures for both drainholes are identical with those of Case **4**. The tubing completion assembly equipment and procedures are also the same.

The embodiment of Case **4** in which tie-in of the drainholes is by means of intermediate liners inserted and cemented in side-tracked holes drilled through elliptical windows by guiding the bit with a retrievable whipstock set in a drillable whipstock packer may also be adapted. The absence of pre-established windows plugged with drillable metal may be remedied in several ways.

The first method calls for milling each elliptical window into the existing casing with a tapered mill guided by a suitable retrievable whipstock. The whipstock required to mill the lowest window and to drill and complete the lowest drainhole is set and oriented in a packer, as in Case **2***a*. The whipstocks used to mill the other windows may then be stacked, each into the adjacent lower whipstock and oriented

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